Appendix F

Statistical Considerations

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Survey Methodology

The Form EIA-23 survey is designed to provide reliable estimates for reserves and production of crude oil, natural gas, and lease condensate for the United States. Operators of crude oil and natural gas wells were selected as the appropriate respondent population because they have access to the most current and detailed information, and therefore, presumably have better reserve estimates than do other possible classes of respondents, such as working interest or royalty owners.

While large operators are quite well known, they comprise only a small portion of all operators. The small operators are not well known and are difficult to identify because they go into and out of business, alter their corporate identities, and change addresses frequently. As a result, EIA conducts extensive frame maintenance activities each year to identify all current operators of crude oil and natural gas wells in the country.

Sampling Strategy

EIA publishes data on reserves and production for crude oil, natural gas, and lease condensate by State for most States, and by State subdivision for the States of California, Louisiana, New Mexico, and Texas. To meet the survey objectives, while minimizing respondent burden, a random sampling strategy has been used since 1977. Each operator reporting on the survey is asked to report production for crude oil, natural gas, and lease condensate for each State/subdivision in which he operates. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided.

The total volume of production varies among the State/subdivisions. To meet the survey objectives while controlling total respondent burden, EIA selected the following target sampling error for the 1998 survey for each product class.

- 1.0 percent for National estimates.
- 1.0 percent for each of the 5 States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas. For selected subdivisions within these States, targets of 1.0 percent or 1.5 percent as required to meet the State target.
- 2.5 percent for each State/subdivision having 1 percent or more of estimated U.S. reserves or production in 1997 (lower 48 States) for any product class.
- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 1997 (lower 48 States) for all 3 product classes.
- 8 percent for States not published separately. The combined production from these States was less than 0.2 percent of the U.S. total in 1997 for crude oil and for natural gas.

The volume of production defining the Certainty stratum, referred to as the **cutoff**, varies by product or State/subdivision. The cutoff criteria and sampling rates are shown in **Table F1**. The Certainty stratum, therefore, has three components.

- **Category I -** *Large Operators:* Operators who produced a total of 1.5 million barrels or more of crude, or 15 billion cubic feet or more of natural gas, or both in 1998.
- **Category II -** *Intermediate Operators:* Operators who produced a total of at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators in 1998.
- **Category III -** *Small Operators:* Operators who produced less than the Category II operators in 1998, but which were selected with certainty. Category III operators were subdivided into operators sampled with certainty (**Certainty**) and operators that were randomly sampled (**Noncertainty**).
  - **Certainty -** A small operators who satisfied any of the following criteria based upon their production shown in the operator frame:

    Operators with annual crude oil production of 200 thousand barrels or more, or reserves of 4 million barrels or more; or annual natural gas production of 1 billion cubic feet or more, or reserves of 20 billion cubic feet or more.

Table F1. 1998 EIA–23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs			Noncertainty Sample Number of	
	Crude Oil (mbbls)	Gas (mmcf)	Certainty Operators	Single State Operators	Multi–State Operators
Alabama Onshore	107	1,000	54	4	5
Alaska	0	0	7	0	0
Arkansas	21	1,000	123	25	27
California Unspecified	17	88	2	2	0
California Coastal Region Onshore	200	1,000	24	1	3
California Los Angeles Basin Onshore	200	25	24	4	2
California San Joaquin Basin Onshore	200	1,000	41	5	6
Colorado	200	1,000	134	20	23
Florida Onshore	200	1,000	4	0	1
Illinois	200	27	26	18	19
Indiana	12	1	17	4	14
Kansas	85	1,000	205	140	40
Kentucky	37	1,000	21	15	11
Louisiana Unspecified	73	183	0	0	0
Louisiana North	13	633	234	32	27
Louisiana South Onshore	70	1,000	220	34	38
Michigan	200	1,000	62	10	4
Mississippi Onshore	200	1,000	111	2	17
Montana	200	1,000	117	15	16
Nebraska	13	2	35	5	15
New Mexico Unspecified	10	13	26	1	13
New Mexico East	200	1,000	157	0	6
New Mexico West	21	1,000	58	2	1
New York	3	1,000	23	19	5
North Dakota	200	1,000	103	7	10
Ohio	92	1,000	60	72	19
Oklahoma	143	1,000	350	252	65
Pennsylvania	4	1,000	40	23	13
Texas Unspecified	7	118	2	2	0
Texas-RRC District 1	23	800	197	33	46
Texas-RRC District 2 Onshore	200	1,000	213	17	52
Texas-RRC District 3 Onshore	200	1,000	298	36	78
Texas-RRC District 4 Onshore	91	1,000	213	21	44
Texas-RRC District 5	38	630	139	5	26
Texas-RRC District 6	200	1,000	244	33	50
Texas-RRC District 7B	34	82	269	70	76
Texas-RRC District 7C	200	1,000	214	10	76
Texas-RRC District 8	200	1,000	257	9	76
Texas-RRC District 8A	200	1,000	211	10	45
Texas-RRC District 9	52	1,000	178	29	54
Texas-RRC District 10	200	1,000	172	3	16
Utah	200	1,000	63	4	10
Virginia	200	1,000	13	1	1
West Virginia	5	1,000	48	46	17
Wyoming	200	1,000	151	12	30
Offshore Areas	0	0	267	1	7
Other States[a]	125	49	23	2	8
Total			**[b]1,459**	**1,056**	**[b]412**

[a]Includes Arizona, Connecticut, Delaware, Georgia, Idaho, Iowa, Massachusetts, Maryland, Minnesota, Missouri, North Carolina, New Hampshire, Nevada, New Jersey, Oregon, Rhode Island, South Carolina, South Dakota, Tennessee, Washington, and Wisconsin.

[b]Nonduplicative count of operators by States.

Note: Sampling rate was 8 percent except in Alaska, Florida Onshore, Virginia, and Offshore areas where sampling rate was 100 percent.

— = Not applicable.

Source: Energy Information Administration, Office of Oil and Gas.

All other operators with production or reserves in a State/subdivision that exceed selected cutoff levels for that State/subdivision.

The largest operator in each State/subdivision regardless of level of production or reserves.

Operators with production or reserves of oil or gas for six or more State/subdivisions.

- **Noncertainties** - Small operators not in the certainty stratum were classified in a noncertainty stratum and sampled at a rate of 8 percent.

In each State/subdivision the balance between the number of small certainty operators and the sample size was determined in an iterative procedure designed to minimize the number of total respondents. The iteration for each State/subdivision began with only the Category I and Category II operators in the certainty stratum. The size of the sample of small operators required to meet the target variance was calculated based on the variance of the volumes of those operators. For a number of State/subdivisions with high correlations between frame values across pairs of consecutive years, an adjusted target variance was calculated, that utilized the information about the correlations. This allowed the selection of a smaller sample that still met the target sampling error criteria. At each iteration a small operator, beginning with the largest of the Category III operators, was added to the certainty group and the required sample size was again calculated. The procedure of adding one operator at a time stopped when the proportion of operators to be sampled at random dropped below 8 percent. Independent samples of single location operators (operators who, according to the sampling frame, operate in only one State/subdivision) were selected from each State/subdivision using systematic random sampling.

An additional complexity is introduced because some small operators selected for the sample in another region or regions, sometimes report production volumes in a region in which EIA has no previous record of production.

State/subdivision volume estimates are calculated as the sum of the certainty strata and all of the estimates for the sampling strata in that region. The sampling variance of the estimated total is the sum of the sampling variances for the sampling strata. There is no sampling error associated with the certainty stratum.

The square root of the sampling variance is the standard error. It can be used to provide confidence intervals for the State/subdivision totals.

For the States in which subdivision volume estimates are published, the State total is the sum of the individual volume estimates for the subdivisions. The U.S. total is the sum of the State estimates. A sampling variance is calculated for each State subdivision, State, and for the U.S. total.

Total U.S. Reserve Estimates

Conceptually, the estimates of U.S. reserves and production can be thought of as the sum of the estimates for the individual States. Correspondingly, the estimates for the four States for which estimates are published separately by subdivision (California, Louisiana, New Mexico, and Texas) can be thought of as the sum of the estimates by subdivision. The remaining States are not subdivided and may be considered as a single subdivision.

The estimates of year-end proved reserves and annual production for any State/subdivision is the sum of the volumes in the State/subdivision reported by the certainty stratum operators and an estimate of the total volume in the State/subdivision by the noncertainty stratum operators. Mathematically, this may be stated as the following sum:

$$\hat{V}_s \qquad V_{sc} \qquad \hat{V}_{sr}$$

where

$\hat{V}_s$ = estimated total volume in the State/subdivision

V_{SC} = total volume in the State/subdivision reported by Certainty operators

$\hat{V}_{sr}$ = estimated total volume in the State/subdivision of Noncertainty operators.

The total volume of Certainty operators in the State/subdivision is simply the sum of individual operator's volumes:

$$V_{sc} \qquad \overset{n_{sc}}{\underset{m \quad 1}{}} \quad V_{scm}$$

where

n_{SC} = number of Certainty operators reporting production in the State/subdivision

V_{scm} = volume reported by the *m*-th certainty stratum operator in the State/subdivision.

The estimated total volume of Noncertainty operators in the State/subdivision is the weighted sum of the reports of the noncertainty sample operators:

$$\hat{V}_{sr} = \sum_{m=1}^{n_{sr}} W_{srm} V_{srm}$$

where

n_{sr} = number of Noncertainty operators reporting production in the State/subdivision

V_{srm} = volume reported by the *m*-th Noncertainty sample operator in the State/subdivision

W_{srm} = weight for the report by the *m*-th Noncertainty sample operator reporting production in the State/subdivision.

In many State/ subdivisions, the accuracy of the oil and gas estimates was improved by using the probability proportional to size procedure. This procedure took advantage of the correlation between year-to-year production reports. The weights used for estimating the oil production for a State / subdivision were different from the weights used for estimating the gas production.

The weight used for the estimation is the reciprocal of the probability of selection for the stratum from which the sample operator was selected. In making estimates for a State/ subdivision, separate weights are applied as appropriate for noncertainty operators shown in the frame as having had production in only the State/ subdivision, for those shown as having had production in that State/subdivision and up to four other State/ subdivisions, and for operators with no previous record of production in the State/subdivision. National totals were then obtained by summation of the component totals.

Imputation for Operator Nonresponse

The response rate for Noncertainty operators for the 1998 survey was 99.4 percent, therefore an imputation was made for the production and reserves of the 8 nonresponding operators.

Imputation and Estimation for Reserves Data

In order to estimate reserve balances for National and State/subdivision levels, a series of imputation and estimation steps at the operator level must be carried out. Year-end reserves for operators who provided production data only were imputed on the basis of their production volumes. Imputation was also applied to the small and intermediate operators as necessary to provide data on each of the reserve balance categories (i.e., revisions, extensions, or new discoveries). Finally, an imputation was required for the natural gas data of the small operators to estimate their volumes of associated-dissolved and nonassociated natural gas. The final manipulation of the data accounts for the differences caused by different sample frames from year to year. Each of these imputations generated only a small percentage of the total estimates. The methods used are discussed in the following sections.

The data reported by operator category by Form EIA-23 respondents for the report year 1998 are summarized in **Tables F2, F3, F4, and F5**. The reported data in **Table F2** shows that those responding operators accounted for 97.9 percent of the published production for natural gas shown in **Table 9** and 93.9 percent of the reserves. Data shown in **Table F3** indicate that those responding operators accounted for 95.3 percent of the nonassociated natural gas production and 92.7 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 96.7 percent of published crude oil production and 94.7 percent of the reserves shown in **Table 6**. Additionally, **Table F5** indicates that those responding operators accounted for 100 percent of the published production and 96 percent of the published proved reserves for lease condensate shown in **Table 16**.

Imputation of Year-End Proved Reserves

Category I operators were required to submit year-end estimates of proved reserves. Category II and Category III operators were required to provide year-end estimates of proved reserves only if such estimates existed in their records. Some of these respondents provided estimates for all of their operated properties, others provided estimates for only a portion of their properties, and still others provided no estimates for any of their properties. All respondents did, however, provide annual production data. The production reported by Noncertainty sample operators and the corresponding imputed reserves were weighted to

Table F2. Summary of Total Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Reported and Imputed Data					
Proved Reserves as of 12/31/97	149,878,595	11,753,022	23,033	-	161,654,650
(+) Revision Increases	22,867,374	3,933,811	145,624	-	26,946,809
(–) Revision Decreases	19,981,833	1,640,795	0	-	21,622,628
(+) Extensions	7,245,090	799,803	0	-	8,044,893
(+) New Field Discoveries	835,143	147,710	0	-	982,853
(+) New Reservoirs in Old Fields	1,982,423	92,763	14,235	-	2,089,421
(–) Production With Reserves in 1998	16,594,101	1,472,599	19,321	-	18,086,021
Proved Reserves Reported as of 12/31/98	146,291,686	13,615,360	163,571	-	160,070,617
Production Without Proved Reserves	25,269	531,885	46,974	-	604,128
Reserves Imputed for Production Without Proved Reserves	166,791	4,323,239	326,375		4,816,405
Subtotal Production	**16,619,370**	**2,004,484**	**66,295**	**-**	**18,690,149**
Subtotal Proved Reserves 1998	**146,458,477**	**17,938,599**	**489,946**	**-**	**164,887,022**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	3,859	118,270	77,086	199,215
Production Without Proved Reserves	0	7,046	182,787	133,731	323,564
Subtotal Production	0	10,905	301,057	210,817	522,779
Weighted Subtotal Production	**0**	**10,905**	**301,057**	**619,889**	**931,851**
Proved Reserves Reported	0	21,475	1,085,344	713,771	1,820,590
Reserves Imputed for Reported Production Without Proved Reserves	0	21,482	1,372,175	1,368,707	2,762,364
Subtotal Proved Reserves	0	42,957	2,457,519	2,082,478	4,582,954
Weighted Subtotal Proved Reserves	**0**	**42,957**	**2,457,519**	**5,055,502**	**7,555,978**
Total Production in 1998	**16,619,370**	**2,015,389**	**367,352**	**619,889**	**19,622,000**
Total Proved Reserves as of 12/31/98	**146,458,477**	**17,981,556**	**2,947,465**	**5,055,502**	**172,443,000**

– = Not applicable.

Notes: Table 9 totals include imputed and estimated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998.

Table F3. Summary of Nonassociated Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/97	121,784,153	10,230,055	13,678	-	132,027,886
(+) Revision Increases	18,920,040	3,464,824	39,642	-	22,424,506
(–) Revision Decreases	16,774,920	1,262,641	0	-	18,037,561
(+) Extensions	6,632,689	739,359	0	-	7,372,048
(+) New Field Discoveries	731,321	145,942	0	-	877,263
(+) New Reservoirs in Old Fields	1,792,251	73,297	14,235	-	1,879,783
(–) Production With Reserves in 1998	13,907,665	1,296,034	12,168	-	15,215,867
Proved Reserves Reported as of 12/31/98	119,234,863	12,097,445	55,387	-	131,387,695
Production Without Proved Reserves	25,048	423,209	43,778	-	492,035
Reserves Imputed for Production Without Proved Reserves	172,831	2,920,142	302,068	-	3,395,042
Subtotal Production	**13,932,713**	**1,719,243**	**55,946**	**-**	**15,707,902**
Subtotal Proved Reserves 1998	**119,407,694**	**15,017,587**	**357,455**	**-**	**134,782,737**
State Level Reported and Imputed Data					
Production With Proved Reserves	—	—	—	—	—
Production Without Proved Reserves	—	—	—	—	—
Subtotal Production	—	—	—	—	—
Weighted Subtotal Production	—	—	—	—	—
Proved Reserves Reported	—	—	—	—	—
Reserves Imputed for Reported Production Without Proved Reserves	—	—	—	—	—
Subtotal Proved Reserves	—	—	—	—	—
Weighted Subtotal Proved Reserves	—	—	—	—	—
Total Production in 1998	**13,932,713**	**1,719,243**	**55,946**	**-**	**15,707,902**
Total Proved Reserves as of 12/31/98	**119,407,694**	**15,017,587**	**357,455**	**-**	**134,782,737**

– = Not applicable.
Notes: Table 10 totals include imputed and estimated nonassociated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.
Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998.

Table F4. Summary of Crude Oil Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/97	19,560,638	787,760	6,946	-	20,355,344
(+) Revision Increases	2,163,945	202,379	41,405	-	2,407,729
(–) Revision Decreases	1,720,906	183,522	7,144	-	1,911,572
(+) Extensions	281,464	15,010	0	-	296,474
New Field Discoveries	148,004	2,142	0	-	150,146
(+) New Reservoirs in Old Fields	97,672	19,104	0	-	116,776
(–) Production With Reserves in 1998	1,713,103	80,119	3,570	-	1,796,792
Proved Reserves Reported as of 12/31/98	18,816,152	762,761	37,684	-	19,616,597
Production Without Proved Reserves	514	35,246	3,878	-	39,638
Reserves Imputed for Production Without Proved Reserves	3,189	230,810	26,092		260,091
Subtotal Production	**1,713,617**	**115,365**	**7,448**	**-**	**1,836,430**
Subtotal Proved Reserves 1998	**18,819,341**	**993,571**	**63,776**	**-**	**19,876,688**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	893	19,482	13,832	34,207
Production Without Proved Reserves	0	1,308	30,879	22,733	54,920
Subtotal Production	0	2,201	50,361	36,565	89,127
Weighted Subtotal Production	**0**	**2,201**	**50,361**	**102,008**	**154,570**
Proved Reserves Reported	0	5,270	152,156	152,825	310,251
Reserves Imputed for Reported Production Without Proved Reserves	0	3,384	198,723	200,927	403,034
Subtotal Proved Reserves	0	8,654	350,879	353,752	713,285
Weighted Subtotal Proved Reserves	**0**	**8,654**	**350,879**	**797,779**	**1,157,312**
Total Production in 1998	**1,713,617**	**117,566**	**57,809**	**102,008**	**1,991,000**
Total Proved Reserves as of 12/31/98	**18,819,341**	**1,002,225**	**414,655**	**797,779**	**21,034,000**

– = Not applicable.

Notes: Table 6 totals include imputed and estimated crude oil proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1998.

Table F5. Summary of Lease Condensate Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/97	1,178,325	88,274	21	-	1,266,620
(+) Revision Increases	248,781	41,451	459	-	290,691
(–) Revision Decreases	241,057	17,871	0	-	258,928
(+) Extensions	74,077	6,101	0	-	80,178
(+) New Field Discoveries	32,310	3,753	0	-	36,063
(+) New Reservoirs in Old Fields	34,272	533	251	-	35,056
(–) Production With Reserves in 1998	156,528	15,826	233	-	172,587
Proved Reserves Reported as of 12/31/98	1,170,704	105,963	498	-	1,277,165
Production Without Proved Reserves	497	3,043	424	-	3,964
Reserves Imputed for Production Without Proved Reserves	3,081	19,270	2,638		24,989
Subtotal Production	**157,025**	**18,869**	**657**	**-**	**176,551**
Subtotal Proved Reserves 1998	**1,173,785**	**125,233**	**3,136**	**-**	**1,302,154**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	0	452	202	654
Production Without Proved Reserves	0	36	663	735	1,434
Subtotal Production	0	36	1,115	937	2,088
Weighted Subtotal Production	**0**	**36**	**1,115**	**1,298**	**2,449**
Proved Reserves Reported	0	0	3,395	1,052	4,447
Reserves Imputed for Reported Production Without Proved Reserves	0	223	6,962	5,426	12,611
Subtotal Proved Reserves	0	223	10,357	6,478	17,058
Weighted Subtotal Proved Reserves	**0**	**223**	**10,357**	**23,266**	**33,846**
Total Production in 1998	**157,025**	**18,905**	**1,772**	**1,298**	**179,000**
Total Proved Reserves as of 12/31/98	**1,173,785**	**125,456**	**13,493**	**23,266**	**1,336,000**

– = Not applicable.

Notes: Table 15 totals include imputed and estimated lease condensate proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1998.

estimate the full noncertainty stratum when calculating reserves and production as previously described in the section "Total U.S. Reserves Estimates" in this appendix.

A year-end proved reserves estimate was imputed from reported production data in each case where an estimate was not provided by the respondent. The reported annual production was multiplied by a reserves-to-production (R/P) ratio (**Table F6**) characteristic of operators of similar size in the region where the properties were located. The regional R/P ratios in this report are averages calculated by dividing the mean of reported reserves by the mean of reported production for selected respondents of similar size who did report estimated reserves. A cutoff level for each region was determined based upon the largest Certainty operator that reported production, but did not provide a reserve estimate. Data from respondents whose production in a region exceeded the regional cutoff level was excluded from the R/P ratio calculation for that region. In addition, operators that had R/P ratios that exceeded 25 to 1 and Category I operators were excluded from the respondents selected to calculate the characteristic regional R/P ratio. All other respondents who reported both production and reserves were used to calculate the regional R/P ratio characteristic.

The R/P ratio varied significantly from region to region. This variation was presumably in response to variation in geologic conditions and the degree of development of crude oil and natural gas resources in each area. The average R/P ratio was computed for regional areas similar to the National Petroleum Council regional units (**Figure F1**). These units generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be somewhat similar. **Table F6** lists the R/P ratio calculated for each region that required such imputations and the number of observations on which it was based.

The regional R/P ratio is determined primarily to provide a factor that can be applied to the production reported by operators without reserve estimates to provide an estimate of the reserves of these operators when aggregated to the regional level. The average R/P ratio, when multiplied by each individual production in the distribution of R,P pairs used to calculate it, will exactly reproduce the sum of the reported reserves in the distribution.

Imputation of Annual Changes to Proved Reserves by Component of Change

Category II and Category III operators that do not keep reserves data were not asked to provide estimates of beginning-of-year reserves or annual changes to proved reserves by component of change, i.e., revisions, extensions, and discoveries. When they did not provide estimates, these volumes were estimated by applying an algebraic allocation scheme which preserved the relative relationships between these items within each State/subdivision, as reported by Category I and Category II operators, and also preserved an exact annual reserves balance of the following form:

Table F6. Statistical Parameters of Reserve Estimation Equation by Region for 1998

Region Number	Region	Number of Nonzero R/P Pairs: Oil	Gas	Lease Condensate	Characteristic Multipliers: Oil	Gas	Lease Condensate
2	Pacific Coast States	17	16	3	[a]6.6	[a]8.0	[a]6.1
3	Western Rocky Mountains	44	52	13	6.9	10.4	[a]6.1
4	Northern Rocky Mountains	88	67	6	6.7	8.8	[a]6.1
5	West Texas and East New Mexico	196	200	50	7.0	7.1	6.5
6 + 6A	Western Gulf Basin and Gulf of Mexico	273	285	182	6.2	6.6	6.2
7	Mid-Continent	207	193	59	6.6	8.1	8.0
8 + 9	Michigan Basin and Eastern Interior	58	43	6	5.8	9.7	[a]6.1
10 + 11	Appalachians	17	47	1	[a]6.6	13.5	[a]6.1
	United States	900	903	320	6.6	8.0	6.1

[a]Multiplier of the U.S. national average is assumed. Effect of the multiplier on the related natural gas or lease condensate reserves estimate is negligible in these regions.

Source: Based on data filed on Form EIA-23,"Annual Survey of Domestic Oil and Gas Reserves, 1998".

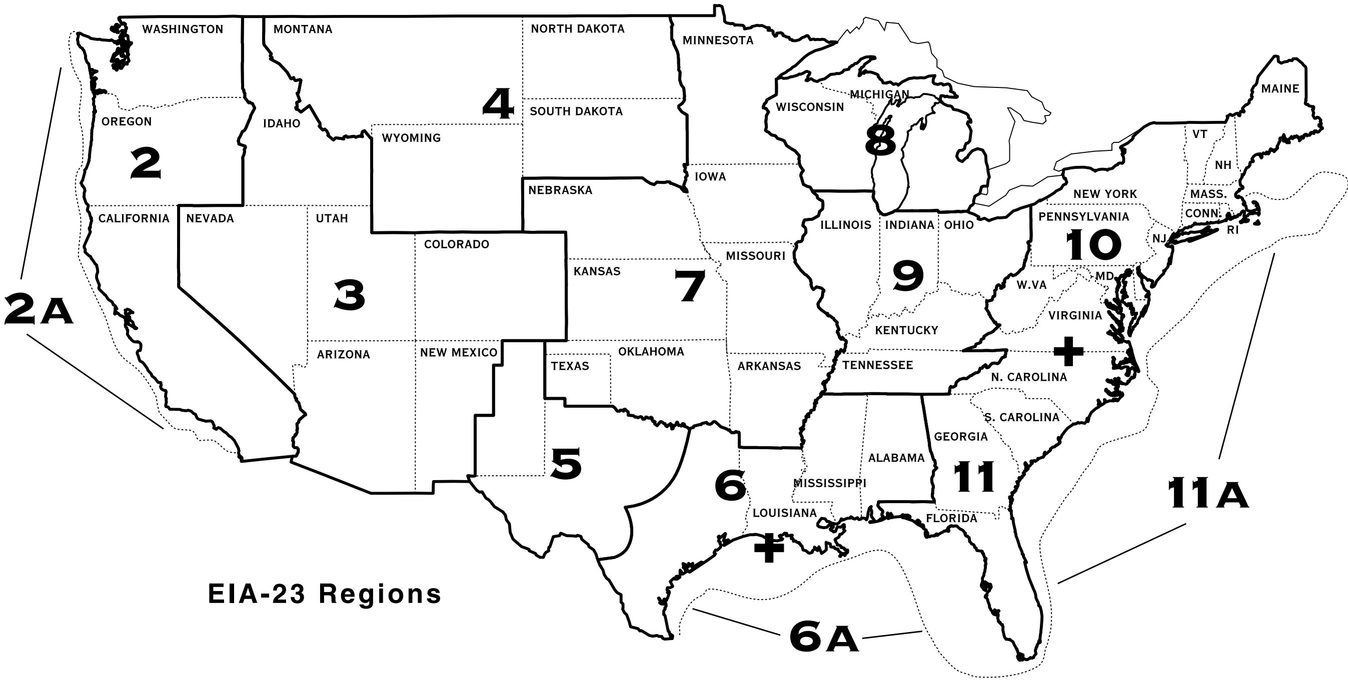
Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
– Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Published Proved Reserves at End of Report Year

A ratio was calculated as the sum of the annual production and year-end proved reserves of those respondents who did not provide the reserves balance components, divided by the sum of year-end proved reserves and annual production of those respondents of similar size who did provide these quantities. This ratio was then multiplied by each of the reserves balance components reported by Category I and some Category II operators, to obtain imputed volumes for the reserves balances of the other Category II operators and Certainty and Noncertainty operators. These were then added to the State/subdivision totals.

Imputation of Natural Gas Type Volumes

Operators in the State/subdivision certainty and noncertainty strata were not asked to segregate their natural gas volumes by type of natural gas, i.e., nonassociated natural gas (NA) and associated-dissolved natural gas (AD). The total estimated year-end proved reserves of natural gas and the total annual production of natural gas reported by, or imputed to, operators in the State/subdivision certainty and noncertainty strata were, therefore, subdivided into the NA and AD categories, by State/subdivision, in the same proportion as was reported by Category I and Category II operators in the same area.

Figure F1. Form EIA-23 Regional Boundaries



Source: Energy Information Administration, Office of Oil and Gas.

Adjustments

The instructions for Schedule A of Form EIA-23 specify that, when reporting reserves balance data, the following arithmetic equation must hold:

Proved Reserves at End of Previous Year
+ Revision Increases
– Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Proved Reserves at End of Report Year

Any remaining difference in the State/subdivision annual reserves balance between the published previous year-end proved reserves and current year-end proved reserves not accounted for by the imputed reserves changes was included in the adjustments for the area. One of the primary reasons that adjustments are necessary is the instability of the Noncertainty operators sampled each year. About 24 percent of the Noncertainty stratum operators sampled in 1997 were sampled again in 1998. There is no guarantee that in the smaller producing States/subdivision the same number of small operators will be selected each year, or that the operators selected will be of comparable sizes when paired with operators selected in a prior year. Thus, some instability of this stratum from year to year is unavoidable, resulting in minor adjustments.

Some of the adjustments are, however, more substantial, and could be required for any one or more of the following reasons:

- The frame coverage may or may not have improved between survey years, such that more or fewer Certainty operators were included in 1998 than in 1997.
- One or more operators may have reported data incorrectly on Schedule A in 1997 or 1998, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1998 from operators not in the frame or Noncertainty operators not selected for the sample to Certainty operators or Noncertainty operators selected for the sample.
- Operations of properties was transferred during 1998 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1997 operator.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, that was based on the trend reported by the large operators, did not reflect the actual trend for the small operators.
- Noncertainty operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.
- The Noncertainty sample for either year in a state may have been an unusual one.

The causes of adjustments are known for some but not all areas. The only problems whose effects cannot be expected to balance over a period of several years are those associated with an inadequate frame or those associated with any actual trend in reserve changes for small operators not being the same as those for large operators. EIA continues to attempt to improve sources of operator data to resolve problems in frame completeness.

Sampling Reliability of the Estimates

The sample of Noncertainty operators selected is only one of the large number of possible samples that could have been selected and each would have resulted in different estimates. The standard error or sampling error of the estimates provides a measure of this variability. When probability sampling methods are used, as in the EIA-23 survey, the sampling error of estimates can also be estimated from the survey data.

The estimated sampling error can be used to compute a confidence interval around the survey estimate, with a prescribed degree of confidence that the interval covers the value that would have been obtained if all operators in the frame had been surveyed. If the estimated volume is denoted by $\hat{V}_s$ and its sampling error by S.E. ($\hat{V}_s$), the confidence interval can be expressed as:

$$\hat{V}_s \qquad k\,S.E.(\hat{V}_s)$$

where k is a multiple selected to provide the desired level of confidence. For this survey, k was taken equal to 2. Then there is approximately 95 percent confidence that the interval:

$$\hat{V}_s \qquad 2S.E.(\hat{V}_s)$$

includes the universe value, for both the estimates of reserves and production volumes. Correspondingly, for approximately 95 percent of the estimates in this report, the difference between the published estimate and the value that would be found from a complete survey of all operators is expected to be less than twice the sampling error of the estimate. **Tables F7, F8, F9, and F10** provide estimates for 2S.E. ($\hat{V}_s$) by product. These estimates are directly applicable for constructing approximate 95 percent confidence intervals. For example, the 95 percent confidence interval for dry natural gas proved reserves is 165,146   575 billion cubic feet. The sampling error of $\hat{V}_s$ is equal to the sampling error of the noncertainty estimate $\hat{V}_{sr}$, because the certainty total is not subject to sampling error. The estimated sampling error of a noncertainty estimate is the square root of its estimated sampling variance.

Nonsampling Errors

Several sources of possible error, apart from sampling error, are associated with the Form EIA-23 survey. These include bias due to nonresponse of operators in the sample, proved reserve estimation errors, and reporting errors on the part of the respondents to the survey. On the part of EIA, possible errors include inadequate frame coverage, data processing error, and errors associated with statistical estimates. Each of these sources is discussed below. An estimate of the bias from nonresponse is presented in the section on adjustment for operator nonresponse.

Assessing the Accuracy of the Reserve Data

The EIA maintains an evaluation program to assess the accuracy and quality of proved reserve estimates gathered on Form EIA-23. Field teams consisting of petroleum engineers from EIA's Dallas Field Office conduct technical reviews of reserve estimates and independently estimate the proved reserves of a statistically selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprised of the team's findings to assist them in completing future filings. The magnitude of errors due to differences between reserve volumes submitted by operators on the Form EIA-23 and those estimated by EIA petroleum engineers on their field trips were generally within accepted professional engineering standards.

Respondent Estimation Errors

The principal data elements of the Form EIA-23 survey consist of respondent estimates of proved reserves of crude oil, natural gas, and lease condensate. Unavoidably, the respondents are bound to make some estimation errors, i.e., until a particular reservoir has been fully produced to its economic limit and abandoned, its reserves are not subject to direct measurement but must be inferred from limited, imperfect, or indirect evidence. A more complete discussion of the several techniques of estimating proved reserves, and the many problems inherent in the task, appears in Appendix G.

Reporting Errors and Data Processing Errors

Reporting errors on the part of respondents are of definite concern in a survey of the magnitude and complexity of the Form EIA-23 program. Several steps were taken by EIA to minimize and detect such problems. The survey instrument itself was carefully developed, and included a detailed set of instructions for filing data, subject to a common set of definitions similar to those already used by the industry. Editing software is continually developed to detect different kinds of probable reporting errors and flag them for resolution by analysts, either through confirmation of the data by the respondent or through submission of amendments to the filed data. Data processing errors, consisting primarily of random keypunch errors, are detected by the same software.

Imputation Errors

Some error, generally expected to be small, is an inevitable result of the various estimations outlined. These imputation errors have not yet been completely addressed by EIA and it is possible that estimation methods may be altered in future surveys. Nationally, 5.9 percent of the crude oil proved reserve estimates, 6.1 percent of the natural gas proved reserve estimates, and 0.7 percent of the lease condensate proved reserve estimates resulted from the imputation and estimation of reserves for those Certainty and Noncertainty operators who did not provide estimates for all of their properties, in combination with the expansion of the sample of Noncertainty operators to the full population. Errors for the latter were quantitatively calculated, as discussed in the previous section. Standard errors, for the former, would tend to cancel each other from operator to operator, and are, therefore, expected to be negligible, especially at the

Table F7. Factors for Confidence Intervals (2S.E.) for Dry Natural Gas Proved Reserves and Production, 1998 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1998 Reserves	1998 Production
United States	1003	92
Alabama	18	3
Alaska	0	0
Arkansas	14	2
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	27	3
State Offshore	0	0
Colorado	22	8
Florida	0	0
Kansas	239	30
Kentucky	0	0
Louisiana	10	2
North	11	2
South Onshore	10	1
State Offshore	0	0
Michigan	0	0
Mississippi	8	1
Montana	3	0
New Mexico	0	0
East	0	0
West	0	0
New York	15	1
North Dakota	0	0
Ohio	104	11
Oklahoma	930	84
Pennsylvania	66	2
Texas	173	3
RRC District 1	186	17
RRC District 2 Onshore	20	3
RRC District 3 Onshore	65	8
RRC District 4 Onshore	31	4
RRC District 5	12	1
RRC District 6	16	1
RRC District 7B	29	4
RRC District 7C	34	3
RRC District 8	36	5
RRC District 8A	9	1
RRC District 9	37	5
RRC District 10	212	4
State Offshore	0	0
Utah	52	2
Virginia	0	0
West Virginia	46	3
Wyoming	23	3
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Notes: Confidence intervals are associated with Table 8 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998 and Form EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production,” 1998.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 1998 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1998 Reserves	1998 Production
United States	1068	98
Alabama	19	3
Alaska	0	0
Arkansas	28	3
California	50	12
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	3	0
San Joaquin Basin Onshore	28	3
State Offshore	0	0
Colorado	25	9
Florida	0	0
Kansas	257	32
Kentucky	0	0
Louisiana	11	2
North	11	2
South Onshore	11	2
State Offshore	0	0
Michigan	0	0
Mississippi	8	1
Montana	3	0
New Mexico	0	0
East	0	0
West	0	0
New York	15	1
North Dakota	12	1
Ohio	104	11
Oklahoma	990	89
Pennsylvania	66	2
Texas	192	3
RRC District 1	194	17
RRC District 2 Onshore	21	4
RRC District 3 Onshore	69	9
RRC District 4 Onshore	32	4
RRC District 5	12	1
RRC District 6	17	1
RRC District 7B	34	5
RRC District 7C	38	3
RRC District 8	41	6
RRC District 8A	13	1
RRC District 9	44	6
RRC District 10	235	4
State Offshore	0	0
Utah	55	2
Virginia	0	0
West Virginia	47	3
Wyoming	24	3
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Notes: Confidence intervals are associated with Table 9 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998.

Table F9. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 1998
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1998 Reserves	1998 Production
United States	102	10
Alabama	2	0
Alaska	0	0
Arkansas	1	0
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	15	2
Florida	0	0
Illinois	5	1
Indiana	3	1
Kansas	57	7
Kentucky	11	0
Louisiana	7	1
North	7	1
South Onshore	5	1
State Offshore	0	0
Michigan	1	0
Mississippi	11	1
Montana	1	0
Nebraska	3	0
New Mexico	0	0
East	0	0
West	0	0
North Dakota	1	0
Ohio	11	1
Oklahoma	47	7
Pennsylvania	1	0
Texas	10	2
RRC District 1	14	1
RRC District 2 Onshore	0	0
RRC District 3 Onshore	4	1
RRC District 4 Onshore	1	0
RRC District 5	1	0
RRC District 6	4	1
RRC District 7B	4	1
RRC District 7C	3	0
RRC District 8	50	1
RRC District 8A	22	2
RRC District 9	10	1
RRC District 10	13	2
State Offshore	0	0
Utah	13	0
West Virginia	0	0
Wyoming	33	0
Federal Offshore	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[a]	3	0

[a]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.

Notes: Confidence intervals are associated with Table 6 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EI-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998.

Table F10. Factors for Confidence Intervals (2S.E.) for Lease Condensate Proved Reserves and Production, 1998 (Million Barrels of 42 U.S. Gallons)

State and Subdivision	1998 Reserves	1998 Production
United States	6	1
Alabama	0	0
Alaska	0	0
Arkansas	0	0
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	0	0
Florida	0	0
Kansas	1	0
Kentucky	0	0
Louisiana	0	0
North	0	0
South Onshore	1	0
State Offshore	0	0
Michigan	0	0
Mississippi	0	0
Montana	0	0
New Mexico	0	0
East	0	0
West	0	0
North Dakota	0	0
Oklahoma	5	1
Texas	1	0
RRC District 1	0	0
RRC District 2 Onshore	1	0
RRC District 3 Onshore	4	1
RRC District 4 Onshore	1	0
RRC District 5	0	0
RRC District 6	0	0
RRC District 7B	0	0
RRC District 7C	0	0
RRC District 8	0	0
RRC District 8A	0	0
RRC District 9	0	0
RRC District 10	1	0
State Offshore	0	0
Utah and Wyoming	0	0
West Virginia	0	0
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Notes: Confidence intervals are associated with Table 15 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1998.

National level of aggregation. In States where a large share of total reserves is accounted for by Category III and smaller Category II operators, the errors are expected to be somewhat larger than in States where a large share of total reserves is accounted for by Category I and larger Category II operators.

Frame Coverage Errors

Of all the sources of controllable error connected with the Form EIA-23 survey, errors in the operator frame were expected to be the most important. If the frame does not list all operators in a given State, the sample selected from the frame for the State will not represent the entire operator population, a condition called undercoverage. Undercoverage is a problem with certain States, but it does not appear to be a problem with respect to the National proved reserve estimates for either crude oil or natural gas. While it is relatively straightforward to use existing sources to identify large operators and find addresses for them, such is not the case for small operators. A frame such as that used in the 1998 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. These States are not likely to allocate sufficient resources to keep track of all operators on a current basis. Some undercoverage of this type seems to exist, particularly, with reference to natural gas operators. EIA is continuing to work to remedy the undercoverage problem in those States where it occurred.

Calculation of Reserves of Natural Gas Liquids and Dry Natural Gas

Natural Gas Liquids Reserve Balance

The published reserves, production, and reserves change statistics for crude oil, lease condensate, and natural gas, wet after lease separation, were derived from the data reported on Form EIA-23 and the application of the imputation methods discussed previously. The information collected on Form EIA-64A was then utilized in converting the estimates of the wet natural gas reserves into two components: plant liquids reserve data and dry natural gas reserve data. The total natural gas liquids reserve estimates presented in **Table 14** were computed as the sum of plant liquids estimates (**Table 15**) and lease condensate (**Table 16**) estimates.

To generate estimates for each element in the reserves balance for plant liquids in a given producing area, the first step was to group all natural gas processing plants that reported this area as an area-of-origin on their Form EIA-64A, and then sum the liquids production attributed to this area over all respondents. Next, the ratio of the liquids production to the total wet natural gas production for the area was determined. This ratio represented the percentage of the wet natural gas that was recovered as natural gas liquids. Finally, it was assumed that this ratio was applicable to the reserves and each component of reserve changes (except adjustments), as well as production. Therefore, each element in the wet natural gas reserves balance was multiplied by this recovery factor to yield the corresponding estimate for plant liquids. Adjustments of natural gas liquids were set equal to the difference between the end of previous year reserve estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Natural Gas Reserve Balance

This procedure involved downward adjustments of the natural gas data, wet after lease separation, in estimating the volumes of natural gas on a fully dry basis. These reductions were based on estimates of the gaseous equivalents of the liquids removed (in the case of production), or expected to be removed (in the case of reserves), from the natural gas stream at natural gas processing plants. Form EIA-64A collected the volumetric reduction, or **shrinkage**, of the input natural gas stream that resulted from the removal of the NGL at each natural gas processing plant.

The shrinkage volume was then allocated to the plant's reported area or areas of origin. Because shrinkage is, by definition, roughly in proportion to the NGL recovered, i.e. the NGL produced, the allocation was in proportion to the reported NGL volumes for each area of origin. However, these derived shrinkage volumes were rejected if the ratio between the shrinkage and the NGL production (gas equivalents ratio) fell outside certain limits of physical accuracy. The ratio was expected to range between 1,558 cubic feet per barrel (where NGL consists primarily of ethane) and 900 cubic feet per barrel (where NGL consists primarily of natural gasolines). When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin.

This imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 1998 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,404 cubic feet of natural gas shrinkage per barrel of NGL recovered. The total shrinkage volume (reported plus imputed) for all plants reporting a given area of origin was then subtracted from the estimated value of natural gas production, wet after lease separation, yielding dry natural gas production for the area. The amount of the reduction in the wet natural gas production was then expressed as a percentage of the wet natural gas production. Dry natural gas reserves and reserve changes were determined by reducing the wet natural gas reserves and reserve changes by the same percentage reduction factor.

A further refinement of the estimation process was used to generate an estimate of the natural gas liquids reserves in those States with coalbed methane fields. The States where this procedure was applied were Alabama, Colorado, Kansas, New Mexico, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. The assumption was made that coalbed methane fields contained little or no extractable natural gas liquids. Therefore, when the normal shrinkage procedure was applied to the wet gas volume reserve components, the estimate of State coalbed methane volumes were excluded and were not reduced for liquid extraction. Following the computation for shrinkage, each coalbed field gas volume reserve components was added back to each of the dry gas volume reserve components in a State. The effect of this is that the large increases in reserves in some States from coalbed methane fields did not cause corresponding increases in the State natural gas liquids proved reserves.

Adjustments of dry natural gas were set equal to the difference between the end of previous year reserves estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Each estimate of end of year reserves and report year production has associated with it an estimated sampling error. The standard errors for dry natural gas were computed by multiplying the wet natural gas standard errors by these same percentage reduction factors. **Table F7** provides estimates for 2 times the $S.E.(\hat{V}_s)$ for dry natural gas.